BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Order Instituting Rulemaking to Develop an Electricity Integrated Resource Planning Framework and to Coordinate and Refine Long-Term Procurement Planning Requirements.	Rulemaking 16-02-007

SOUTHERN CALIFORNIA EDISON COMPANY'S (U 338-E) OPENING COMMENTS ON ASSIGNED COMMISSIONER AND ADMINISTRATIVE LAW JUDGE'S RULING INITIATING PROCUREMENT TRACK AND SEEKING COMMENT ON POTENTIAL RELIABILITY ISSUES

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Pursuant to the *Assigned Commissioner and Administrative Law Judge's Ruling Initiating Procurement Track and Seeking Comment on Potential Reliability Issues*, dated June 20, 2019 ("Ruling") and the *Administrative Law Judge's Ruling Denying, in Part, and Granting, in Part, Motion of California Community Choice Association for Amended Ruling and Extension of Time*, dated July 11, 2019, Southern California Edison Company ("SCE") respectfully submits these opening comments and its responses to the questions set forth in the Ruling.

I.

INTRODUCTION

A. The California Electric System Faces Reliability Risks

SCE appreciates the California Public Utilities Commission's ("Commission's") recent attention to existing and emerging issues affecting the California electric system's ability to ensure resource adequacy ("RA") and maintain reliability. The state's electric system is rapidly evolving on multiple fronts. The state has set aggressive goals to reduce greenhouse gas

(“GHG”) emissions and increase renewable and zero-carbon generation resources.[1] California must pursue these clean energy goals in a manner that ensures electricity is reliable and affordable for all customers. The Commission has recognized that “California is currently entering an era of tighter generation supplies than we have experienced in recent years.”[2] With the retirement of once-through cooling (“OTC”) units, a desire to minimize the need to run thermal generating units from an environmental policy basis, and increasing economic pressures facing thermal generating units as zero-marginal cost resources like wind and solar proliferate, the state’s electric system is transitioning away from its reliance on conventional thermal generation.[3] Additionally, other western U.S. states are beginning to aggressively pursue their own renewables and carbon reduction goals, which is reducing the amount of potential excess generation capacity they can commit to California’s RA program on a year-ahead and month-ahead basis.

As a result, California is confronting a significant system RA shortfall beginning as early as September 2021 unless expedited action is taken to develop new clean energy resources and potentially extend existing natural gas-fired generation resources on an interim basis.

SCE strongly supports the Commission’s actions to address risks to the reliability of the state’s electric system, including initiating an integrated resource planning (“IRP”) “procurement track” that considers whether additional procurement is needed to ensure the California Independent Operator (“CAISO”) system has sufficient resources to meet system RA requirements and maintain reliability over the near-, medium-, and long-term. As the Commission stated, reliability is not an afterthought or secondary to environmental goals; it is “coequal and integral to a successful IRP process.”[4] While the RA proceeding addresses

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1 *See* Senate Bill (“SB”) 100 (2018); SB 32 (2016); Exec. Order B-55-18 (2018); Exec. Order S-3-05 (2005).

2 *Ruling of Assigned Commissioner and Administrative Law Judge Seeking Comment on Policy Issues and Options Related to Reliability*, R.16-02-007, November 16, 2018, at 3.

3 *See id.* at 3-4.

4 Decision (“D.”) 19-04-040 at 131.

planning reserve margins ("PRMs") and flexible resource needs on a year-ahead and month-ahead basis, procurement requirements for local resources on a three-year ahead basis, and is considering a framework for central procurement of multi-year local RA, the IRP process is the venue providing a comprehensive look at all operational resource needs through 2030 and must consider the necessity of procuring and supporting all new and existing resources that are required for a reliable, clean, and cost-effective electric system.[5] The Commission has made it clear to all load-serving entities ("LSEs") "that there is a shared responsibility among all of them for a reliable electric system that meets the state's environmental goals at least cost."[6] SCE appreciates the Commission's actions to ensure reliability and believes that near-term action or direction is needed given the timing and potential scale of the expected system RA need. In the sections below, SCE offers suggestions based on its own analysis of how such action should proceed.

B. **Commission Staff's Analysis Correctly Identifies a Likely System RA Shortfall as Early as 2021, and the Need is Likely to Be Significantly Higher than the Capacity Quantity Included in the Ruling's Procurement Proposals**

The Ruling is a critical first step towards ensuring the CAISO system will have sufficient capacity to meet system RA requirements over the next few years. In addition to formally initiating the IRP procurement track, the Ruling describes recent trends observed by Commission staff in the RA market, including a tightening of the bilateral market, a decline in the robustness of competitive solicitations, and the fact that a number of LSEs have not been able to comply with system requirements for the 2019 RA compliance year.[7] Given these signs, staff used public sources of information to analyze the CAISO system supply stack in the near- to medium-

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[5] *See id.* at 132-133; D.19-02-022 at 6-19.
[6] D.19-04-040 at 135.
[7] *See* Ruling at 6.

term (between 2019 and 2024) "to better understand the liquidity in the bilateral [RA] market and consider whether there are sufficient resources to meet peak system reliability needs."[8]

Staff found that "[f]or the resources available in this time horizon, there will likely be a growing reliance on import capacity, especially when [OTC] units retire as expected at the end of 2020," and that in 2021, "it is possible that all of the [maximum import capability ('MIC')] could be needed just to meet the system [RA] requirement, which is more than double the historical usage of imports for system [RA] purposes."[9] Based on historical data on the imported RA used to meet system peak requirements and other factors, the Ruling concludes that "we are growing increasingly concerned with the ability of the bilateral markets to transact and meet 2021 [RA] requirements, given such limited in-state supply," and notes "the possibility that additional units may mothball and/or retire, exacerbating the tightness of in-state supply."[10]

The Ruling proposes three potential solutions to the need for additional system RA as early as 2021: (1) requiring that each LSE procure its proportional share of a total 2,000 megawatts ("MW") new peak capacity statewide to come online by August 1, 2021; (2) Commission staff beginning discussions with the Statewide Advisory Committee on Cooling Water Intake Structures ("SACCWIS") to the State Water Resources Control Board ("Water Board") regarding potentially postponing the retirement of one or more OTC units to accommodate the schedule for new resources to come online to meet system reliability needs; and (3) requiring SCE to solicit 500 MW of capacity from existing resources that are without a contract past 2021, as part of a medium-term contract of two to five years, with costs allocated to all LSEs with RA obligations.[11]

SCE thanks Commission staff for proactively studying the CAISO system's ability to meet near- and medium-term system RA requirements. As discussed in response to question 1

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[8] *Id.*
[9] *Id.* at 6-7, 13.
[10] *Id.* at 13.
[11] *See id.* at 14-16.

below, SCE shares staff's concerns that as early as 2021, there will not be enough capacity on the system for all LSEs to meet their collective system RA requirements. Indeed, California may be thousands of MW short. Similar to staff, SCE performed an analysis based on public sources of information to evaluate CAISO system peak capacity needs on an annual basis for the years 2020 through 2030 to identify if there will be sufficient resources available to satisfy system RA requirements. SCE agrees with staff's conclusion that there will likely be a system RA shortfall in 2021. Based on SCE's analysis, the expected system RA shortfall is likely to be 5,500 MW or more in 2021, and continue over the next several years.

C. The Ruling's Potential Solutions to the Expected System RA Shortfall are a Starting Point; Expedited Action and Some Modifications are Needed

To address the estimated system RA shortfall and maximize California's ability to meet its system RA requirements, SCE supports the Ruling's proposal to require each LSE to procure its proportional share of a total 2,000 MW incremental RA capacity[12] to come online by August 1, 2021. But 2,000 MW is only a starting point. Thousands of additional MW are likely to be needed. In order to enhance the likelihood that such additional incremental RA capacity is available, the Commission should pursue one of two paths: (1) require LSEs to procure their proportional share of a defined amount of incremental RA capacity; or (2) make clear to all LSEs that they will be held responsible for meeting their system RA requirements, and that meeting those requirements is likely to require the development of incremental resources beyond the initial 2,000 MW given the likelihood of an overall system RA shortfall and the expected magnitude of the shortfall.

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[12] As explained in response to question 5, SCE suggests that the Commission classify this as a procurement requirement for "incremental" RA capacity rather than "new" capacity and clarify that the determination of what resources are incremental is based on whether they were included in the Commission's baseline assumptions (i.e., resources are incremental if they were not included in the baseline assumptions). The Commission should also be clear that whatever capacity amount is chosen by the Commission is measured in MW that count towards system RA requirements.

If the Commission chooses the first path of Commission-directed procurement, it should take several actions to maximize the chances of an effective procurement and resource development process. First, the Commission should look for ways to expedite the standard procurement and approval processes as time is very short for the procurement and development of incremental (and especially new) RA capacity by August 1, 2021. The current processes will not support significant incremental resource capacity coming online by August 2021.
SCE recommends the Commission expedite its IRP procurement track decision on near- to medium-term reliability issues and require procurement as soon as possible. Similar to the process that allowed SCE to successfully procure and bring online new third-party contracted and utility-owned energy storage resources in a very short timeframe in its Aliso Canyon Energy Storage ("ACES") 1 solicitation, the Commission should also provide a process in which it will act expeditiously to approve any contracts for incremental RA capacity.

Moreover, the Commission should issue an Assigned Commissioner's ruling authorizing the investor-owned utilities ("IOUs") to begin their solicitations as soon as possible, with any procurement contingent on a final decision determining the procurement need and the details of the procurement authorization.[13] There will likely be insufficient time for each IOU to meet their respective shares of incremental system RA procurement if IOU solicitation launches are delayed to the end of the year given the amount of time otherwise needed to launch and conduct solicitations, submit selected resources to the Commission for approval, and then successfully develop approved projects by August 1, 2021.

Second, in its decision on near- to medium-term reliability issues, the Commission should direct LSEs to procure sufficient incremental RA capacity to meet the estimated system RA need over the near- and medium-term (at least through 2023). Based on SCE's analysis, the need for incremental system RA capacity beginning in 2021 is likely to significantly exceed 2,000 MW,

[13] Community choice aggregators ("CCAs") and electric service providers ("ESPs") already have the ability to begin their solicitations without Commission approval.

and the need is projected to continue for the next several years. It will be very difficult for approximately 40 LSEs to simultaneously solicit, procure, and develop 2,000 MW of incremental RA capacity by August 1, 2021,[14] given the market confusion that will likely occur as dozens of buyers compete for limited new resource project options and the fact that normal development lead times for new projects typically exceed the time available between now and August 2021. Yet, the need for incremental system RA capacity will likely exceed 2,000 MW.

Besides expediting the procurement and approval processes as discussed above, the Commission should act now to order procurement for incremental RA capacity needed in 2022 and 2023, or at a minimum, allow the IOUs to meet their projected share of system RA needs beyond the initial incremental 2,000 MW being considered for all LSEs. Delaying a decision on 2022 and 2023 procurement needs will result in another emergency situation where resources have to be procured and developed on an extremely short timeframe, reducing the likelihood of getting the capacity online to meet peak demand in 2022 and 2023, and making the procurement costlier for customers.

Accordingly, while LSEs should endeavor to procure incremental RA capacity that can come online by August 1, 2021, the Commission should direct LSEs to procure their proportional share of the Commission's determination of the expected system RA need for 2021 through 2023, and specify required quantities by online dates in 2021, 2022, and 2023.
An Assigned Commissioner's ruling authorizing the IOUs to begin their solicitations as soon as possible should allow the IOUs to launch solicitations to meet their share of the need for 2021, 2022, and 2023.[15] Additionally, the Commission should allow consideration of all options that can meet the need for incremental RA capacity. LSEs should be able to pursue both third-party

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[14] Although SCE is not proposing a central procurement structure, it may be more efficient for the IOUs to procure incremental RA capacity on behalf of all customers in their service areas and recover the costs through the cost allocation mechanism ("CAM"), particularly given the expedited timeframe of the procurement need and the inevitable confusion and uncertainty that will exist among LSEs as they compete for scarce, near-term incremental RA supply options.

[15] Any procurement would be contingent on a final decision determining the procurement need and the details of the procurement authorization.

contracted and LSE-owned resources, and the Commission should authorize the IOUs to consider utility-owned clean resources such as utility-owned storage.

Third, the Commission should clarify the consequences if an LSE fails to meet its procurement obligations under any Commission-directed procurement requirement. If the Commission is considering assessing penalties, SCE suggests RA-like penalties (e.g., $6.66/kilowatt ("kW")-month of deficiency).

SCE also supports the Ruling's proposal regarding potentially postponing the retirement of one or more OTC units. It is going to be difficult, if not impossible, to get sufficient incremental RA capacity online by August 2021 to meet the full expected system RA shortfall. Moreover, the costs to customers of bringing such resources online by August 2021 are likely to be substantially higher than staggering the required availability over 2022 and/or 2023 online dates. Therefore, SCE agrees that the Commission should work with the SACCWIS, the Water Board, and the CAISO to extend the retirement dates of the OTC units that are needed to bridge the time necessary to maintain sufficient system RA resources to ensure the ability of all LSEs to comply with their respective RA requirements. In making this determination, the Commission should consider the costs and benefits of postponing OTC unit retirements when compared to the costs and benefits of accelerated incremental RA capacity. For example, it may be more feasible and cost-effective to postpone the retirement of an OTC unit for one year or more, than for customers to pay the costs for an incremental resource to come online in 2021 instead of 2022 or 2023. In addition, SCE recommends that any contracting with OTC units be done through CAISO reliability-must run ("RMR") agreements to reflect the cost-of-service and targeted resource element of any extended OTC unit.

Finally, SCE requests clarification on the Ruling's proposal that SCE solicit 500 MW of capacity from existing resources that are without a contract past 2021, to be procured as part of a medium-term contract of two to five years, with costs allocated and recovered from all LSEs with RA obligations. The Legislature and the Commission have already established a process whereby each IOU conducts reliability procurement for its service area, with the costs recovered on a nonbypassable basis from all customers in that service area through the CAM. This process has worked effectively and resulted in thousands of MW of CAM procurement by the IOUs. Unless there is a unique need for one LSE to procure the 500 MW in this case, SCE recommends the Commission follow the established CAM process. The 500 MW should be allocated among the three IOUs on behalf of their service areas, with costs recovered by each IOU from all customers in their service area through the CAM.

If the Commission decides this situation presents a unique need for one LSE to conduct the procurement, SCE does not object to conducting the procurement. However, the Commission should clarify why this is a unique situation requiring one LSE to act as the central buyer and the obligation should be rotated among the IOUs if other unique situations occur in the future. Moreover, if SCE is required to undertake procurement on behalf of all customers, the Commission should direct the three IOUs to collect the costs of SCE's procurement from all customers in their service areas through their respective CAM accounts, with Pacific Gas and Electric Company ("PG&E") and San Diego Gas & Electric Company ("SDG&E") billing and collecting such procurement costs as an agent for SCE and being required to transfer the funds so collected to SCE. SCE does not have a mechanism to collect CAM charges from customers outside its own service area and it would be infeasible and unduly burdensome to require SCE to collect the costs from approximately 40 LSEs.

SCE's recommendations are discussed in further detail in the responses to the questions in Section II below.

II.

SCE'S RESPONSES TO QUESTIONS RELATED TO NEAR-TEARM RELIABILITY

1. **Do you believe that there could be reliability challenges as soon as 2021? Why or why not? Include comments on any concerns you have about the staff analysis presented in Section 2.1 of this ruling, and cite to publicly-available data to support your analysis.**

Yes, SCE believes there will likely be a system RA shortfall as soon as 2021. SCE agrees with Commission staff that a number of factors point to a need to examine whether the CAISO system will have sufficient available resources to meet system RA requirements over the next few years. These include:

- **Retirement of a large amount of OTC unit capacity by the end of 2020.** The OTC phaseout regulation has already resulted in the retirement of approximately 10,400 net qualifying capacity ("NQC") MW in the CAISO and Los Angeles Department of Water & Power balancing authority areas.[16] About 6,300 NQC MW of additional OTC units have compliance dates by the end of 2020, and approximately 1,600 NQC MW of additional OTC units have compliance dates by the end of 2024 or 2029.[17]
- **Potential for additional retirements of non-OTC thermal generating units, including for economic reasons due to revenue insufficiency.** Non-OTC thermal generating units are also facing increasing economic pressures as zero-marginal cost resources such as wind and solar proliferate. The CAISO recently stated that "[t]he significant amount of new renewable generation added to the grid continues to put downward economic pressure on the existing gas-fired generation fleet, and this is

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[16] *See* SACCWIS, *2019 Report of the State Advisory Committee on Cooling Water Intake Structures*, March 8, 2019, at 5-6, available at: https://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/saccwis/docs/sac2019fnl.pdf.

[17] *See id.* at 6-7.

expected to be exacerbated as renewable generation is added in the future."[18] For example, General Electric recently announced plans to shut down the Inland Empire Energy Center natural gas plant for economic reasons (one of the plant's turbines had already been mothballed in 2017), which further increases the projected system RA deficiency beginning in 2021.[19]

- **Shifting peak load.** In the 2018 Integrated Energy Policy Report ("IEPR") 1-in-2 peak CAISO coincident forecast, adopted by the California Energy Commission ("CEC") in February 2019, the system peak occurs in September instead of August.[20] Additionally, the CEC started incorporating peak shift impact through its hourly load analysis as part of the 2017 IEPR demand forecast. The peak shift impact accounts for when the CAISO system peak load is expected to occur in future years compared to the traditional mid-day peak hour assumption. "The key driver behind the peak shift phenomenon is increasing expected adoptions of PV systems."[21] The shifting of peak load from August to September and from mid-day to later in the evening reduces solar resources' contribution to meeting peak load and RA requirements since the sun sets earlier in September than August and solar resources cease generating during the evening hours. This peak shift effect will increase as more solar resources are added to the system.
- **Reductions in effective load carrying capability ("ELCC") values for solar and wind.** Recent changes to the ELCC values for solar and wind resources substantially

[18] CAISO, *2018-2019 Transmission Plan*, March 29, 2019, at 22, available at: http://www.caiso.com/Documents/ISO_BoardApproved-2018-2019_Transmission_Plan.pdf.

[19] *See* Reuters, *General Electric to scrap California power plant 20 years early*, June 21, 2019, available at: https://www.reuters.com/article/us-ge-power/general-electric-to-scrap-california-power-plant-20-years-early-idUSKCN1TM2MV.

[20] *See* Ruling at 7, 13.

[21] CEC, *California Energy Demand 2018-2030 Revised Forecast*, CEC-200-2018-002-CMF, February 2018, at 6, available at: https://efiling.energy.ca.gov/getdocument.aspx?tn=223244.

reduce their August and September values.[22] These declining values, which were adopted in D.19-06-026, "will impact the overall supply available to LSEs to count towards their [RA] requirements."[23]

- **Reliance on uncertain level of imports.** As the Ruling states, when looking at the supply stack for 2021, "it is possible that all of the MIC could be needed just to meet the system [RA] requirement, which is more than double the historical usage of imports for system [RA] purposes."[24] Indeed, the actual RA from imports in LSEs' RA filings from 2013 through 2017 generally ranged from 3,000 MW to 5,000 MW for August and September, even though the MIC was significantly higher.[25] The CAISO noted that "[s]ystem-level [RA] requirements met by imports during peak summer hours increased from an average of around 3,600 MW in 2017 to around 4,000 MW in 2018."[26] Relying on RA imports at higher rates than has been observed historically is not realistic. Generators located outside of California can now utilize the CAISO's Energy Imbalance Market ("EIM") to sell excess capacity in short-term markets without having to make the extended year-ahead and/or month-ahead resource commitments that would be needed to support a RA sale to a California entity. Additionally, a number of western U.S. states have increased their renewables requirements and/or are beginning to seek to reduce their GHG emissions, which will limit the amount of excess capacity that has traditionally been used to meet California's peak demands.

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22 *See* Ruling at 8.
23 *Id.*
24 *Id.* at 13.
25 Based on the Commission's annual *Resource Adequacy Reports* for 2013-2017 (Table 4 for 2015-2017 and Tables 6-7 for 2013-2014), available at: https://www.cpuc.ca.gov/RA/.
26 CAISO Department of Market Monitoring ("DMM"), *Import resource adequacy*, September 10, 2018, at 1, available at: http://www.caiso.com/Documents/ImportResourceAdequacySpecialReport-Sept102018.pdf.

- **Shrinking CAISO system capacity margins.** The Commission has recognized that "California is currently entering an era of tighter generation supplies than we have experienced in recent years."[27] Energy and capacity markets are most competitive with either excess capacity and/or free entry to the market (i.e., the ability of a new resource to quickly enter the wholesale energy market to provide energy and capacity). Increasingly, the California market has neither of these attributes; capacity margins are growing thinner due to the aforementioned resource retirements thereby decreasing competition in the market and increasing the possibility that the remaining suppliers may exercise market power. The CAISO's DMM has observed that the CAISO system "showed signs of becoming less competitive" and that "prices may have been significantly in excess of competitive levels in some peak summer hours"[28] The impacts of tightening supply conditions on the wholesale energy market are expected to continue.

Given all of these factors, SCE performed an analysis using publicly available sources of information to evaluate CAISO system capacity needs on an annual basis for the years 2020 through 2030 to identify if there will be sufficient resources available to satisfy system RA requirements. SCE's findings are generally aligned with staff's assessment that there is a potential system RA shortfall in 2021; however, SCE's analysis shows the estimated system RA shortfall is likely to be 5,500 MW or more in 2021, and continue over the next several years. SCE's analysis is discussed in detail below.

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[27] *Ruling of Assigned Commissioner and Administrative Law Judge Seeking Comment on Policy Issues and Options Related to Reliability*, R.16-02-007, November 16, 2018, at 3.

[28] CAISO DMM, *2017 Annual Report on Market Issues & Performance*, June 2018, at 22, available at: http://www.caiso.com/Documents/2017AnnualReportonMarketIssuesandPerformance.pdf; CAISO DMM, *2018 Annual Report on Market Issues & Performance*, May 2019, at 151, available at: http://www.caiso.com/Documents/2018AnnualReportonMarketIssuesandPerformance.pdf.

a) **Overview of SCE's Analysis and Methodology**

SCE's analysis utilizes the forecast CAISO system annual peak demand plus a PRM of 15% to determine whether there is adequate RA capacity for each year between 2020 and 2030 to meet system RA requirements.[29] To determine the amount of capacity that can be counted towards meeting system RA requirements, SCE applied the NQC calculation method, consistent with the current RA counting rules defined by the Commission's RA program.[30] The total system RA capacity available for each year is the sum of the NQCs of all the available resources, including existing and future generation resources, demand response ("DR"), and the CAISO MIC. In SCE's analysis, 2,000 MW of DR[31] and 10,000 MW of imports[32] were assumed to be potentially available and counted towards meeting system RA requirements. Additionally, SCE applied the ELCC methodology adopted by the Commission to determine the NQCs of wind and solar resources for RA counting purposes.[33]

In general, SCE applied the latest publicly available sources of demand and resource assumptions to analyze system RA needs. The 2018 IEPR 1-in-2 year coincident peak demand forecast was used to determine the peak demand assumption.[34] The system RA need varies from

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29 *See* Commission's RA homepage, available at: https://www.cpuc.ca.gov/ra/ ("System requirements are determined based on [] each LSE's CEC adjusted forecast plus a 15% planning reserve margin.").

30 *See* Commission, *Qualifying Capacity Methodology Manual Adopted 2017*, available at: http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442455533.

31 Based on the CAISO's 2019 NQC list as of February 12, 2019, the total DR capacity in September was about 1987.09 MW. *See* CAISO, *Final Net Qualifying Capacity Report for Compliance Year 2019*, available at: http://www.caiso.com/Documents/NetQualifyingCapacityList-2019.xlsx. SCE estimated that 2,000 MW of DR will count towards meeting system RA requirements.

32 Based on historical MIC values, SCE estimated that 10,000 MW of imports will count towards meeting system RA requirements. In 2018, 10,340 of MIC was allocated. Similarly, the RESOLVE assumptions for the 2017-2018 IRP cycle assumed the CAISO effective import capacity is about 9,891 MW.

33 *See* Commission, *Qualifying Capacity Methodology Manual Adopted 2017*, at 5-6, available at: http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442455533.

34 *See Form 1.5b – Statewide, California Energy Demand Update Forecast 2018-2030, Mid Demand Baseline Case, Mid AAEE and AAPV Savings, 1 in 2 Net Electricity Peak Demand by Agency and Balancing Authority (MW)*, available at: https://efiling.energy.ca.gov/GetDocument.aspx?tn=226367&DocumentContentId=57142.

month to month. When evaluating the system RA need for each interim year between 2020 and 2030, SCE compared the available system RA capacity for the month during which the annual peak demand occurs with the annual peak demand from the 2018 IEPR forecast plus the 15% PRM to determine if there is potential system RA deficiency.

The CAISO's 2019 NQC list, as of February 12, 2019, was used to derive the NQC values of existing natural gas, hydro, and nuclear generation resources.[35] SCE used the same ELCC percentages for wind and solar resources for each individual year, which were based on the Commission's proposed ELCC values for the 2020 RA compliance year that were subsequently adopted in D.19-06-026.[36] SCE used the September ELCC values since the system peak occurs in September in the 2018 IEPR forecast. Existing renewable and energy storage (up to the 1,325 MW energy storage mandate) capacity assumptions were based on RESOLVE information with updated 2017 IEPR assumptions.[37] The Reference System Plan build out created by the RESOLVE model[38] was applied to determine the NQC contributions from future resources, including renewables and energy storage.

SCE divided the 10,000 MW of imports into two parts: 4,080 MW of reliable imports and 5,000 MW of potential imports. The remaining 920 MW of imports consist of SCE's 635 MW share of Palo Verde and 285 MW share of Hoover, and are accounted for in SCE's projections of available nuclear and hydro RA capacity, respectively. The reliable imports represent an approximate level of imports that have historically been used towards system RA requirements during peak periods. Historically, actual RA imports during peak hours were always lower than 10,000 MW. Actual system RA from imports in LSEs' collective RA filings

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[35] *See* CAISO, *Final Net Qualifying Capacity Report for Compliance Year 2019*, available at: http://www.caiso.com/Documents/NetQualifyingCapacityList-2019.xlsx.

[36] *See* D.19-06-026 at Ordering Paragraph 19, Appendix A.

[37] The RESOLVE model with updated 2017 IEPR assumptions is available at: ftp://ftp.cpuc.ca.gov/resources/electric/irp2017/resolvemodel.

[38] The Reference System Plan build outs are the resource build outs selected by the RESOLVE model to meet the 42 million metric ton GHG target with updated 2017 IEPR assumptions. The RESOLVE model containing the Reference System Plan build outs is available at the link in the prior footnote.

from 2013 through 2017 generally ranged from 3,000 MW to 5,000 MW for August and September.[39] Further, the Ruling quotes the CAISO's statement that:

> Import RA resources were used to meet an average of around 3,600 MW (or around 7 percent) of system RA requirements during the peak summer hours of 2017. In the summer of 2018, this increased to an average of around 4,000 MW (or around 8 percent) of system [RA] requirements….[40]

As the Ruling recognizes, "[t]hese values are significantly lower than the 2017 and 2018 MIC allocation for these same periods (in 2017, 11,310 MW of MIC was allocated and in 2018, 10,340 MW of MIC was allocated)."[41]

Accordingly, 5,000 MW (4,080 MW of reliable imports plus 920 MW of Palo Verde and Hoover that were included under the nuclear and hydro categories but still treated as reliable) is an appropriate approximation of the reliable imports available to the CAISO system during the annual peak in 2020 through 2030. Indeed, it exceeds the average imports that were used to meet system RA requirements during peak summer hours in 2017 and 2018 by 1,400 MW and 1,000 MW, respectively, so it may overstate the amount of imports that will be available to meet system RA requirements.

SCE's analysis demonstrates that CAISO system RA capacity margins have been shrinking. Figure 1 summarizes the results of SCE's analysis before considering additional uncertainties around the amount of system RA capacity that will be available.

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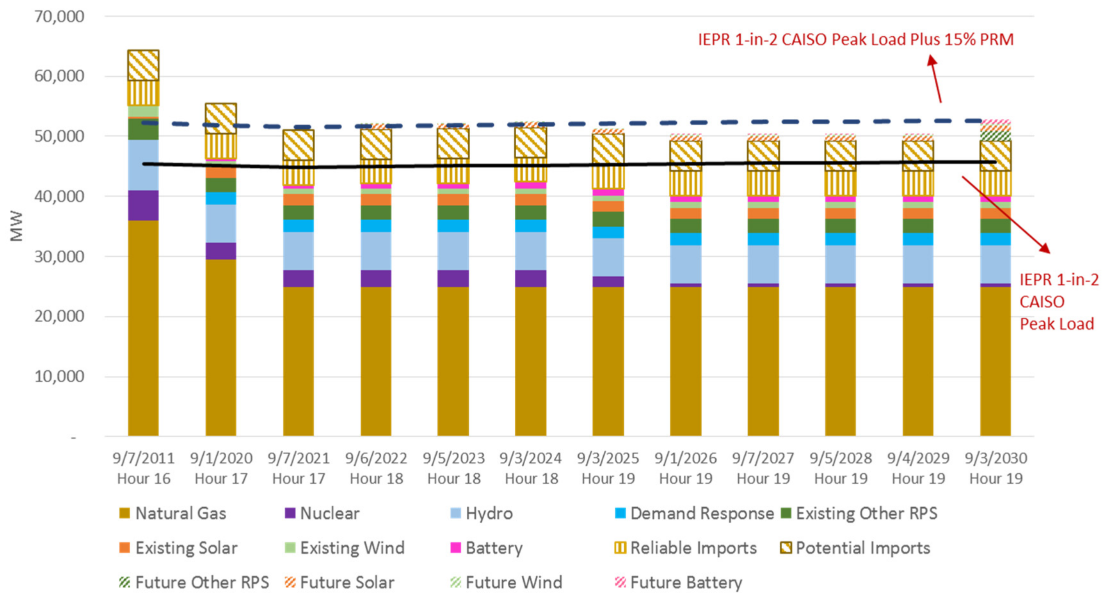
[39] Based on the Commission's annual *Resource Adequacy Reports* for 2013-2017 (Table 4 for 2015-2017 and Tables 6-7 for 2013-2014), available at: https://www.cpuc.ca.gov/RA/.

[40] Ruling at 12.

[41] *Id.* at 13.

Figure 1
CAISO Generation vs IEPR 2018 Peak Load in RA Counting[42]



The reduction in CAISO system RA capacity margins is mainly driven by two factors. First, natural gas generation capacity in the CAISO system declines quickly due to a significant amount of natural gas plant retirements. From 2011 to 2019, there has been about 10,684 MW of natural gas generation retired from the CAISO system. Another 4,577 MW of natural gas generation is expected to retire by the end of 2020. Among the 15,261 MW of natural gas generation capacity that has retired or is expected to retire by 2020, about 7,962 MW corresponds to the retirement of OTC units. Considering the 4,638 MW of natural gas generation that came online between 2011 and 2019 and the 1,284 MW of new natural gas generation that is expected to be online by 2021, there will be an estimated net reduction of 9,339 MW of natural gas generation capacity in the CAISO system from 2011 to 2021.[43]

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[42] The CASIO generation, IEPR 1-in-2 peak load, and IEPR 1-in-2 peak load plus 15% PRM shown in this figure are included in Tables 6 and 7 in Section c below.

[43] *See* Tables 3 and 4 in Section c below and Tables A-1 and A-2 in Appendix A for additional information.

Second, there are significant reductions in the ELCC values that are applied to the maximum capacity of solar and wind resources as the derating factors to determine their NQCs, as a result of the substantial increase in solar and wind penetration during recent years.

As shown in Table 1, the Commission-adopted 2020 ELCC values for the month of September decline from 33% to 14% for solar and from 27% to 15% for wind, compared to the previously adopted 2018 values. It is important to note that the annual peak hour shifts from hour 17 in 2021, to hour 18 in 2022, to hour 19 in 2025 (all hours are in PST time). As a result, the 2020 ELCC values may over-estimate solar resources' contribution to system RA, especially for years starting from 2025 when solar resources' actual production will be minimal during the peak load September hours at hour 19 PST.

Table 1
Comparison of 2018 vs. 2020 Wind and Solar ELCC Values

Wind ELCC Value	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
R. 14-10-010 Previously Adopted 2018 Values	11%	17%	18%	31%	31%	48%	**30%**	**27%**	**27%**	9%	8%	15%
CPUC proposed values for 2020 Compliance Year	14%	12%	28%	25%	25%	33%	**23%**	**21%**	**15%**	8%	12%	13%
Solar ELCC Value	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
R. 14-10-010 Previously Adopted 2018 Values	0%	2%	10%	33%	31%	45%	**42%**	**41%**	**33%**	29%	4%	0%
CPUC proposed values for 2020 Compliance Year	4%	3%	18%	15%	16%	31%	**39%**	**27%**	**14%**	2%	2%	0%

SCE's analysis demonstrates that there may be a system RA shortfall as early as 2021, even assuming 10,000 MW of imports and all other resources are available and counted towards system RA requirements. However, as further discussed in Section c, SCE's Analysis Results, those are not realistic assumptions. The estimated system RA deficiency significantly increases when only reliable imports (and not potential imports) are included, and the shortfall may be even greater when considering other uncertainties. After including only reliable imports and considering other uncertainties, the estimated system RA shortfall in 2021 is likely to be 5,500 MW or more, and continue in that approximate range over the next several years to the extent the need is not met.

b) Resource Assumptions

SCE discussed the primary assumptions used in its analysis in Section a above. This section includes more details on the resource assumptions that were utilized in SCE's analysis.

Natural gas generation resource assumptions: For natural gas generation resources, SCE used the September NQC values from the CAISO's 2019 NQC list as of February 12, 2019, to build the natural gas generation NQC baseline for 2019, with a few exceptions summarized in Table 2. For natural gas plants retiring in 2020 and beyond, the retirement information was primarily based on the CAISO's announced retirement and mothball list as shown in Table 3.[44] All of the natural gas plants listed in Table 3 are part of the OTC retirements. The new natural gas generation capacity and online date information, as shown in Table 4, was obtained from the CAISO's *2018-2019 Transmission Planning Process Unified Planning Assumptions and Study Plan*.[45] All of the new natural gas plants shown in Table 4 are replacement resources for OTC retirement units.

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[44] *See* CAISO, *Announced Retirement and Mothball List*, November 20, 2018, available at: http://www.caiso.com/Documents/AnnouncedRetirement-MothballListPosted112018.html.

[45] *See* CAISO, *2018-2019 Transmission Planning Process Unified Planning Assumptions and Study Plan,* March 30, 2018, available at: http://www.caiso.com/Documents/Final2018-2019StudyPlan.pdf.

Using the 2019 natural gas generation resource outlook as a baseline, the 2011 natural gas generation resource availability was created by adjusting the natural gas plants that were online or retired between 2011 and 2019 based on the information obtained from the CAISO's announced retirement and mothball list. A summary of new and retired natural gas plants between 2011 and 2019 is provided in Appendix A.

Table 2
Key Natural Gas Generation Assumption Deviations Between the CAISO's 2019 NQC list and SCE's Analysis

Resource ID	Resource Name	NQC Capacity (MW)
Resources below were not included in the CAISO's 2019 NQC list, but included in SCE's analysis		
SUTTER_2_PL1X3	SUTTER POWER PLANT AGGREGATE[46]	500
Resources below were included in the CAISO's 2019 NQC list, but excluded in SCE's analysis		
INLDEM_5_UNIT 1	Inland Empire Energy Center, Unit 1[47]	340
MOSSLD_2_PSP1	MOSS LANDING POWER BLOCK 1[48]	510
MOSSLD_2_PSP2	MOSS LANDING POWER BLOCK 2	510

[46] Sutter was not included on the CAISO's 2019 NQC list; however, it is also not listed as retired or mothballed on the CAISO's announced retirement and mothball list. Therefore, SCE assumed that Sutter could be available to count towards system RA requirements. If Sutter is not available, that will increase the estimated system RA shortfall.

[47] Inland Empire Energy Center, Unit 1 was excluded because it is on the CAISO's announced retirement and mothball list and General Electric has announced plans to shut down the plant.

[48] Moss Landing 1 and 2 were excluded because they have a December 31, 2020 OTC compliance date.

Table 3
Summary of Natural Gas Plants Retiring After 2019

RESOURCE_ID	GENERATOR NAME	Capacity (MW)	Retirement Date
ALAMIT_7_UNIT 1	ALAMITOS GEN STA. UNIT 1	175	12/31/2020
ALAMIT_7_UNIT 2	ALAMITOS GEN STA. UNIT 2	175	12/31/2020
ALAMIT_7_UNIT 3	ALAMITOS GEN STA. UNIT 3	332	12/31/2020
ALAMIT_7_UNIT 4	ALAMITOS GEN STA. UNIT 4	336	12/31/2020
ALAMIT_7_UNIT 5	ALAMITOS GEN STA. UNIT 5	498	12/31/2020
ALAMIT_7_UNIT 6	ALAMITOS GEN STA. UNIT 6	495	12/31/2020
HNTGBH_7_UNIT 2	HUNTINGTON BEACH GEN STA. UNIT 2	226	12/31/2020
ORMOND_7_UNIT 1	ORMOND BEACH GEN STA. UNIT 1	741	12/31/2020
ORMOND_7_UNIT 2	ORMOND BEACH GEN STA. UNIT 2	750	12/31/2020
REDOND_7_UNIT 5	REDONDO GEN STA. UNIT 5	179	12/31/2020
REDOND_7_UNIT 6	REDONDO GEN STA. UNIT 6	175	12/31/2020
REDOND_7_UNIT 8	REDONDO GEN STA. UNIT 8	496	12/31/2020
Total		**4,577**	

Table 4
Summary of New Natural Gas Plants Coming Online After 2017

RESOURCE_ID	GENERATOR NAME	Capacity (MW)	Online Date
OTC Alamitos	Alamitos	640	4/1/2020
OTC Huntington	Huntington Beach	644	3/1/2020
OTC Carlsbad	Encina Gas Peaker	500	10/1/2018
OTC_Stanton Peakers	Stanton Peaker Facility	98	11/1/2019

Hydro resource assumptions: For hydro resources, the September NQC values from the CAISO's 2019 NQC list as of February 12, 2019, were applied for all the years between 2019 and 2030 in the analysis, assuming the total capacity of California hydro resources remains the same for future years beyond 2019. The total NQC of hydro resources in the CAISO system counted towards the September 2019 RA capacity is 6,073 MW.[49]

Nuclear resource assumptions: The Diablo Canyon nuclear power plants 1 and 2 (1,122 MW and 1,118 MW) and the SCE share of Palo Verde nuclear power imports (635 MW)

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[49] An additional 285 MW of Hoover share was also counted towards system RA requirements in the hydro category in SCE's analysis.

were included in SCE's analysis. Both the capacity and retirement date of the Diablo Canyon nuclear power plants were obtained from the CAISO's *2018-2019 Transmission Planning Process Unified Planning Assumptions and Study Plan*, which indicates PG&E plans to retire one of the two Diablo Canyon power plants by the end of 2024 and the remaining one by the end of 2025.[50]

Renewable and energy storage resource assumptions: The contract capacity values from RESOLVE were used for existing renewable and energy storage resources (up to the 1,325 MW energy storage mandate), and the Reference System Plan build outs created by RESOLVE were used for future generic renewable and energy storage resources, as shown in Table 5.
For wind and solar resources, the NQC values in SCE's analysis were determined by multiplying the capacity values obtained from RESOLVE by the Commission's 2020 ELCC values for those resources. For small hydro, biomass, and geothermal resources, 100% of contract capacities were counted towards the system RA capacity. For the energy storage mandate, 100% of contract capacities were also counted towards the system RA capacity consistent with the RESOLVE assumption that all mandated energy storage is 4-hour storage and the Commission's rule that 4-hour storage will contribute 100% of its capacity to system RA. For future energy storage, according to RESOLVE, 2,104 MW of generic batteries with 1.3-hour duration were selected in the Reference System Plan. As a result, their contributions to system RA were de-rated to 32.5% of the total capacities to represent an equivalent 4-hour duration capability.

Table 5
2017-2018 IRP Reference System Plan Renewable Resource Build outs (MW)

	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
Future Solar	5,852								64	5,916
Future Wind	1,145								1,101	2,246
Future Geothermal									1,700	1,700
Future Battery					187				1,917	2,104

[50] *See* CAISO, *2018-2019 Transmission Planning Process Unified Planning Assumptions and Study Plan,* March 30, 2018, available at: http://www.caiso.com/Documents/Final2018-2019StudyPlan.pdf.

c) SCE's Analysis Results

Under SCE's analysis, Table 6 shows the system RA capacity available during the annual peak for each year from 2020 through 2030, broken down by each resource category and reliable and potential imports.

Table 6
CAISO Generation (RA Capacity (MW))

Date	Natural Gas	Nuclear	Existing Other RPS	Existing Solar	Existing Wind	Future Other RPS	Future Solar	Future Wind	Hydro	Demand Response	Battery	Future Battery	Reliable Imports	Potential Imports
9/7/2011 Hour 16	35,920	5,121	3,612	281	1,926	-	-	-	8,311		-		4,080	5,000
9/1/2020 Hour 17	31,272	2,875	2,232	4,910	1,550	-	977	84	5,986	2,000	548	-	4,080	5,000
9/7/2021 Hour 17	26,695	2,875	2,165	4,886	1,508	-	1,169	84	5,883	2,000	673	-	4,080	5,000
9/6/2022 Hour 18	26,695	2,875	1,902	775	1,320	-	525	64	6,502	2,000	870	-	4,080	5,000
9/5/2023 Hour 18	26,695	2,875	1,886	775	1,468	-	609	147	6,445	2,000	895	-	4,080	5,000
9/3/2024 Hour 18	26,695	2,875	1,851	772	1,460	-	918	147	6,181	2,000	1,151	-	4,080	5,000
9/3/2025 Hour 19	26,695	1,753	1,837	0	1,530	-	0	162	6,599	2,000	1,151	-	4,080	5,000
9/1/2026 Hour 19	26,695	635	1,832	0	1,478	-	0	162	6,490	2,000	1,151	187	4,080	5,000
9/7/2027 Hour 19	26,695	635	2,236	0	1,477	-	0	162	6,433	2,000	1,151	187	4,080	5,000
9/5/2028 Hour 19	26,695	635	2,080	0	1,527	-	1	162	6,204	2,000	1,151	187	4,080	5,000
9/4/2029 Hour 19	26,695	635	2,072	0	1,702	335	1	162	6,173	2,000	1,151	187	4,080	5,000
9/3/2030 Hour 19	26,695	635	2,077	0	1,713	801	1	162	5,959	2,000	1,151	2,104	4,080	5,000

Table 7 shows the 2018 IEPR 1-in-2 year peak load and the 2018 IEPR 1-in-2 peak load plus the 15% PRM, which is the system RA requirement, for each year from 2020 through 2030.

Table 7
IEPR 1-in-2 Peak Load and IEPR 1-in-2 Peak Load Plus 15% PRM (MW)

Date	IEPR 1-in-2 Peak Load	IEPR 1-in-2 Peak Load Plus 15% PRM
9/1/2020 Hour 17	45,115	51,882
9/7/2021 Hour 17	44,825	51,549
9/6/2022 Hour 18	44,937	51,678
9/5/2023 Hour 18	45,072	51,833
9/3/2024 Hour 18	45,150	51,923
9/3/2025 Hour 19	45,320	52,118
9/1/2026 Hour 19	45,417	52,230
9/7/2027 Hour 19	45,574	52,410
9/5/2028 Hour 19	45,619	52,462
9/4/2029 Hour 19	45,682	52,534
9/3/2030 Hour 19	45,770	52,636

Table 8 shows the total RA capacity in the CAISO system compared to the system RA requirement when including reliable imports and not including potential imports. As explained in Section a above, 5,000 MW of reliable imports (4,080 MW of reliable imports plus 920 MW of Palo Verde and Hoover that were included under the nuclear and hydro categories but still treated as reliable imports) is an appropriate approximation of the reliable imports available to the CAISO system during peak hours in 2020 through 2030. In fact, this may be overstating the amount of imports that will be available as the average imports used towards system RA requirements in summer peak hours in 2017 and 2018 were approximately 3,600 MW and 4,000

MW, respectively. Therefore, SCE believes the estimated system RA shortfall based on counting reliable imports, but not potential imports, towards system RA requirements is a conservative estimate.

Indeed, import RA capacity may become more limited as other western U.S. states significantly increase their renewables targets and reduce their use of GHG-emitting resources, which have been the traditional source of much of California's imports. Moreover, the ability of non-CAISO market participants to access the CAISO's EIM on an hourly basis (and potentially day-ahead basis as CAISO seeks to expand the operation of it EIM) to realize economic rents instead of committing capacity on a firm basis to California on a year-ahead or month-ahead basis will also reduce the amount of capacity available to provide dependable system RA resources to CAISO entities.

Table 8
Estimated System RA Shortfall (RA Capacity (MW))

Date	Total Generation without Imports	Reliable Imports	Potential Imports	Total Generation with Imports	System RA Requirement	Estimated System RA Shortfall
9/1/2020 Hour 17	46,359	4,080	0	50,439	51,882	1,443
9/7/2021 Hour 17	41,952	4,080	0	46,032	51,549	5,517
9/6/2022 Hour 18	43,140	4,080	0	47,220	51,678	4,458
9/5/2023 Hour 18	43,165	4,080	0	47,245	51,833	4,588
9/3/2024 Hour 18	43,421	4,080	0	47,501	51,923	4,422
9/3/2025 Hour 19	42,299	4,080	0	46,379	52,118	5,739
9/1/2026 Hour 19	41,198	4,080	0	45,278	52,230	6,952
9/7/2027 Hour 19	41,198	4,080	0	45,278	52,410	7,132
9/5/2028 Hour 19	41,198	4,080	0	45,278	52,462	7,184
9/4/2029 Hour 19	41,198	4,080	0	45,278	52,534	7,256
9/3/2030 Hour 19	43,708	4,080	0	47,788	52,636	4,848

As shown in Table 8, with the assumptions discussed above, the estimated system RA shortfall is approximately 5,500 MW in 2021 and 4,500 MW in 2022 and 2023.

There are several uncertainties in SCE's analysis that could easily cause the estimated system RA shortfall in 2021 and beyond to exceed the numbers set forth in Table 8.
For example, the available imports during the annual peak could be less than 5,000 MW.
The average imports used to meet system RA requirements during the peak summer hours in 2018 was around 4,000 MW. Particularly given (1) generators' ability to utilize the CAISO's EIM to sell excess capacity, and (2) increasing renewables requirements (including integration) outside California potentially reducing the amount of dispatchable capacity available to make

forward commitments to California, it may not be realistic to assume available imports will increase above 2018 levels.

Additional thermal generating units may also be mothballed or retired. As addressed above, the CAISO has recognized the increasing economic pressure on thermal generating units with the substantial amounts of new renewable generation being added to the grid. Large natural gas plants have already mothballed or retired due to economic pressures given their uncertain operating future in California, and that is likely to continue unless LSEs commit to contract for gas-fired generation on a sustainable basis. For instance, it was recently announced that the Inland Empire Energy Center natural gas plant will shut down for economic reasons.

There are also a number of other factors that could affect the system RA shortfall, including, for example, extended outages, market inefficiencies such as generators and scheduling coordinators holding back some resources from their supply plans to make them available for planned outage substitutions or to mitigate Resource Adequacy Availability Incentive Mechanism penalties, and forecasting uncertainties around distributed energy resource adoption and peak demand growth.

Considering all of these of factors that were not included in the estimated system RA shortfall results in Table 8, it is reasonable to assume the estimated system RA shortfall may increase by as much as 2,500 MW in 2021 beyond the initial 5,500 MW estimated shortfall, resulting in a total estimated 2021 system RA deficiency of approximately 8,000 MW.

If the retirement of any OTC units are postponed, that may reduce the estimated system RA shortfall. However, there are political, environmental, and operational limitations on the amount of capacity from OTC units that can be extended, and even if the retirement of some OTC units is postponed, it is likely to be only for one to two years, and will not fully cover the potential system RA shortfall. Thus, SCE does not believe that postponing the retirement of OTC units is a full solution to meeting the estimated system RA shortfall in 2021 and beyond.

2. Are you concerned about increasing reliance on imported capacity for meeting resource adequacy requirements? Why or why not?

Yes, SCE agrees with Commission staff's concern that in 2021, all of the MIC may be needed to meet system RA requirements if no incremental system RA resources are developed, which is more than double the historical usage of imports for system RA purposes.[51] It is not realistic to rely on imports in excess of historical levels to meet future system RA requirements. Generators outside of California now have more options to sell excess capacity in the CAISO's EIM, which may decrease RA imports to the CAISO system. Additionally, as other western U.S. states implement renewables portfolio standards and clean energy policies, these other states may have fewer dispatchable resources available to commit to California. As explained in response to question 1, SCE's analysis assumed 5,000 MW of reliable imports. SCE believes the Commission should assume that the CAISO system will have no more than 5,000 MW of imports available to meet system RA requirements, rather than using the MIC.

3. Should the Commission be concerned about specific local and/or flexible resource adequacy needs, or only the system needs identified herein? Explain.

The Commission should be concerned about system, local, and flexible RA needs, but the IRP procurement track should focus on ensuring there are sufficient resources to satisfy system RA needs, leaving local and flexible RA issues to the active RA proceeding, R.17-09-020, scoped to resolve issues associated with procurement of local and flexible RA.

Specifically, in the RA proceeding, the Commission has recognized that the procurement of local RA through a central procurement entity is likely a better approach for California than the current fragmented LSE bilateral-based procurement structure.[52] However, due to "lack of a

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[51] *See* Ruling at 13.
[52] *See* D.18-06-030 at 32; D.19-02-022 at 6.

consensus as to a central procurement mechanism that satisfies the objectives outlined in the Track 1 decision, the Commission elect[ed] to delay implementation of a central procurement structure to allow additional time for a series of workshops."[53]

These subsequent local RA workshops have resulted in three primary models of central procurement (full, residual, and hybrid) that have undergone a thorough assessment through the workshop process. The three central procurement models differ significantly in how an LSE that has procured local resources would be able to utilize those resources to meet their local needs and other needs (e.g., system and flexible RA, Renewables Portfolio Standard, etc.).
The Commission expects to issue a decision in R.17-09-020 to address and adopt implementation details for a central procurement structure in the fourth quarter of 2019. Given that the Commission is contemplating a central procurement structure to address local (and potentially flexible) RA needs in R.17-09-020, SCE recommends that the Commission focus on system needs in this proceeding and not mandate any local procurement as that could create conflicts with the outcome of the central procurement structure to be adopted in the RA proceeding.

The Commission also establishes flexible RA[54] requirements applicable to all LSEs in the RA proceeding.[55] The CAISO publishes an effective flexible capacity ("EFC") list providing the amount of a resource that counts toward meeting the flexible RA need.[56] While California's decarbonized electricity future will require a significant amount of flexible resources to meet grid reliability, that need can be sufficiently met through existing RA resources at this time.

Accordingly, with the RA proceeding actively addressing procurement to meet local and flexible RA needs, SCE recommends that the Commission not require incremental procurement

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[53] D.19-02-022 at 17.
[54] Flexible RA consists of resources capable of ramping to serve system ramping needs due to a combination of load changes and intermittent renewable generation output.
[55] *See* D.18-06-031 (adopting flexible RA requirements for 2019); D.19-06-026 (adopting flexible RA requirements for 2020).
[56] *See, e.g.*, CAISO, *Final Effective Flexible Capacity List for 2019 Compliance Year*, available at: http://www.caiso.com/Documents/EffectiveFlexibleCapacityList-2019.xlsx.

to meet local and/or flexible RA needs in the IRP procurement track and instead maintain a focus on ensuring sufficient resources are available to meet system RA needs.

4. If a need for system reliability resources in the near-term is identified within this proceeding, will there be sufficient time to bring new resources online to meet the need? If not, should the Commission pursue delays to the OTC retirement schedules to bridge this short-term gap? Why or why not? If the Commission pursues OTC retirement date delays, on which plants and for how long should we request the delays?

As discussed previously, SCE agrees there is a near-term need for incremental RA capacity to address a likely system RA deficiency in 2021. Based on SCE's analysis, the estimated system RA shortfall is likely to be 5,500 MW or more. SCE also agrees that urgent action is needed to address this near-term need for system RA.

An online date of August 1, 2021 for incremental system RA resources is extremely aggressive. It is particularly challenging given the difficulties and complications of having approximately 40 LSEs engage in solicitations at the same time to procure thousands of MW under an expedited timeframe. Based on the date of the Ruling and the proposed schedule for a proposed decision and initiation of procurement activities, the time needed to conduct a solicitation, and the time for Commission approval of any contracts or utility investments, it is likely that developers will have less than one year to develop their projects. If a project requires a new interconnection, that alone could require several years depending on the extent of the interconnection work necessary. Even behind-the-meter resources would most likely seek more time to develop projects of any size. Requiring an online date of August 1, 2021 essentially limits the procurement activity to projects that just by circumstance happen to be in an advanced development state without an explicit offtake agreement, and it is unlikely this pool of resources adds up to thousands of MW of RA capacity. There also may be a large cost premium for projects to meet an August 2021 online date due to limited supply-side competition and extensive demand-side competition.

In its response to question 5, SCE recommends several actions to maximize the chances of bringing incremental resources online by August 1, 2021. SCE also suggests that the Commission allow LSEs to procure incremental resources with online dates in 2022 and 2023 in addition to 2021. Moreover, clarifying that the procurement requirement is for incremental resources not included in the Commission's baseline assumptions, which may include some existing resources that were retired and/or mothballed, may expand the pool of eligible resources that could come online by August 1, 2021. Even with those efforts, however, there will likely be a need to delay the retirement schedules of some OTC units to bridge the identified system RA gap and meet near-term system RA needs in 2021, and for 2022 and 2023 to the extent that all needs could not be met on an accelerated 2021 commercial online date basis.

SCE supports the Ruling's proposal that Commission staff initiate discussion with the SACCWIS regarding the potential for such OTC retirement extensions. The Commission should work with the SACCWIS, the Water Board, and the CAISO to postpone the retirement dates of the OTC units that are needed to ensure that collective LSE system RA requirements can be met while incremental clean system RA resources are developed. Commission and CAISO staff are best suited to identify which OTC unit's retirement date delays would be most effective, and for how long the OTC extensions should operate from both a reliability and cost perspective.

In making these determinations, the Commission should weigh the costs and benefits of postponing OTC unit retirements when compared to the costs and benefits (and feasibility) of bringing incremental resources online on an accelerated basis. The costs of bringing incremental resources online by August 1, 2021 are going to be meaningfully higher than such resources coming online by 2022 or 2023, when there would be more supply-side competition and more time to minimize development costs. The Commission needs to balance how much more customers should pay for incremental resources to come online by August 1, 2021, instead of extending the retirement date of one or more OTC units.

Finally, SCE recommends the selected OTC units whose retirement dates are postponed be contracted by the CAISO under RMR agreements. CAISO RMR agreements are the appropriate contractual mechanism because they were developed to address resource-specific needs to reliably maintain the grid with a Federal Energy Regulatory Commission-regulated cost of service mechanism, and have market power. The RMR agreement will provide equitable cost-of-service compensation to OTC asset owners sufficient to reasonably maintain the availability of the selected resources. Additionally, the CAISO RMR agreement is an annual agreement that can be extended one year at a time if necessary. This mechanism is consistent with retaining the OTC units while they are necessary for system reliability, but allowing the contracts to expire in a timely fashion once the resource is no longer needed. The CAISO (and the Commission and CEC) are also best positioned to work with the agencies that must allow such resources to operate including the SACCWIS, the Water Board, and the appropriate air quality management districts. As with other RMR agreements, any RMR agreements with OTC units should reduce the system RA requirements of all LSEs.

5. Comment on the proposed requirements in Section 2.2 of this ruling for 2,000 MW of new resource adequacy capacity procured and online by August 1, 2021, procured on a proportional and all-source basis by all jurisdictional LSEs. Parties may also propose an alternative requirement.

SCE supports the Ruling's proposed requirements with some modifications. As explained in response to question 1, 2,000 MW is only a first step towards the amount of incremental system RA capacity that is likely to be needed in 2021 through 2023. SCE's analysis demonstrates that the estimated system RA shortfall is likely to be 5,500 MW or more in 2021, and to continue in that approximate range for the next several years. Thus, thousands more MW of incremental system RA will likely be needed. To address this significant system RA need, the Commission should order all LSEs to do their proportional share of the needed procurement over a specified 2021-2023 commercial operation date schedule. Alternatively, the

Commission could use this IRP procurement track to put all LSEs on notice that they will be required to meet their system RA requirements, that the development of incremental resources beyond the initial 2,000 MW is likely to be needed to satisfy such requirements given the expected system RA shortfall, and that the failure to develop incremental resources will not be a valid reason to seek a waiver for non-compliance with system RA requirements.[57]

If the Commission decides to require procurement of the needed system RA capacity, it is likely to be difficult for approximately 40 LSEs to procure 2,000 MW of incremental RA capacity by August 1, 2021. The timeframe to procure and develop incremental (and especially new) resources is very short and the number of projects that are currently at the advanced development stage to meet an August 2021 online date is likely to be small. For the 2,000 MW procurement amount that is contemplated in the Ruling, an LSE-based procurement approach may be inefficient and potentially ineffective. For procurement where there is a large requirement and a large number of resources that can potentially meet the need, an LSE-based procurement is a reasonable manner to procure needed capacity. Where the availability of resources is constrained and/or the quantity to be procured is relatively small compared to the total procurement entity population, however, such procurement is more effectively performed by one or more central entities.

Here, the incremental resources that can come online by August 1, 2021 are limited, and the proposed 2,000 MW quantity to be procured will be allocated on a load ratio share over a large number of LSEs. Because the number of projects that will be capable of meeting an August 2021 commercial operation date will be limited, the competition of approximately 40 LSEs seeking to procure their proportional share of the 2,000 MW incremental system RA

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[57] In D.19-06-026, the Commission declined to extend the existing local RA waiver process to system or flexible RA requirements, but encouraged further discussion of the issue through workshops or in a later phase of the RA proceeding. *See* D.19-06-026 at 18. SCE believes there is a need for a limited system and flexible RA waiver to address situations where an LSE acting as the provider of last resort is required to serve unplanned load. The Commission also declined to adopt this limited waiver, but encouraged SCE to raise the proposal in a later phase of the RA proceeding. *See id.* at 55-56.

requirement will be intense and likely create significant commercial uncertainty and increased costs for buyers as potential project developers consider their contract options. In the event that LSE-based procurement fails to procure the necessary resources, there will not be sufficient time for another entity to procure such resources and bring them online by August 1, 2021. Moreover, having approximately 40 LSEs conduct solicitations during the same period will make it more difficult to develop the most effective and least cost overall portfolio to satisfy the CAISO system's RA need.

The issues described above are exactly the issues discussed in the RA proceeding that has resulted in Commission direction to implement a central procurement methodology for local RA. Although SCE has supported the procurement of reliability needs by each LSE for system and flexible RA, there will remain circumstances where central procurement to ensure that reliability goals are met effectively and efficiently is necessary. In this case, it may be more efficient for the IOUs, as central buyers, to procure the needed incremental RA capacity on behalf of all customers in their service areas and recover the costs through the CAM. However, SCE does not object to the Commission proceeding with an LSE-based procurement approach if it determines requiring each LSE to procure its share of the need is the most effective or policy-balanced approach to meet the need. LSE-based procurement can be more effective if the Commission directs LSEs to procure the full expected system RA need for 2021 through 2023, and allows LSEs to procure their load share of incremental system RA resources with 2021, 2022, and 2023 online dates as discussed below, as that would expand the pool of eligible resources and give LSEs more flexibility in shaping their long-term resource portfolios.

If the Commission chooses to require Commission-directed procurement to satisfy the expected system RA need, SCE recommends some modifications to the Ruling's proposed procurement requirement to enhance the likelihood of a successful procurement and resource development process as addressed below. First, the Commission should expedite actions related to the procurement to the extent possible and order LSEs to procure to meet system RA needs in 2021 through 2023, and not just 2021. Second, the Commission should allow LSE-owned resources as an option for meeting the need. Third, the Commission should clarify eligibility and other requirements for the procurement (i.e., fully define what is an incremental resource, including how incrementality will apply to demand-side resources).

a) <u>Expedited Action is Needed to Satisfy the Estimated System RA Shortfall in 2021 Through 2023</u>

As addressed above, there is little time to develop sufficient incremental RA capacity to satisfy the estimated system RA deficiency in 2021, and there are likely to be only a limited number of projects at a late enough development stage that they can meet an August 1, 2021 online date. However, the need is not limited to 2021. SCE's analysis shows an estimated system RA shortfall of 5,500 MW or more in 2021, continuing in that approximate range for the next several years. To the extent there is not enough incremental RA capacity added to the system in 2021 (and the remaining need is met with OTC retirement extensions for one or two years), there will still be a need for incremental system RA capacity in 2022 and 2023.

In its decision on near- to medium-term reliability issues, SCE recommends that the Commission, as one option, order LSEs to procure their proportional shares of the Commission's determination of the full need for system RA for 2021 through 2023. Alternatively, the Commission should be clear that it will not be providing subsequent procurement requirements for incremental system RA capacity, and instead instruct that each LSE will be responsible for meeting its system RA requirements, even if it requires the development of incremental system RA resources beyond the LSE's initial load share of the 2,000 MW procurement requirement.

Given the time it will take to procure, develop, and interconnect thousands of MW of incremental resources, the Commission and LSEs should act now to meet 2021, 2022, and 2023 needs. The Ruling does not identify any separate regulatory process to identify and approve procurement to meet system RA needs in 2022 and 2023, and by the time another process could be completed, the state could be faced with an emergency situation requiring expedited procurement and resource development to meet 2022 and 2023 needs. That would make meeting such needs more difficult and much costlier for customers. LSEs may realistically only have a single opportunity to attempt to fill system RA needs for 2021 to 2023, and the Commission should require (or at least allow in the case of the IOUs) this procurement in its upcoming decision.

SCE agrees there is a substantial expected system RA need in 2021 and suggests keeping an August 1, 2021 online date as a strong preference for LSEs' procurement. But the Commission should also consider authorizing LSEs to procure incremental resources that can come online in 2022 and 2023. SCE recommends an online date range of August 1, 2021 through August 1, 2023. Incremental RA capacity is needed in all of these years as discussed above, and expanding the eligible online dates will increase the number of resources that can participate in LSEs' solicitations, thus increasing the potential viability and cost-effectiveness of the procurement. Including 2021, 2022, and 2023 online dates in LSE solicitations also has the added benefit of providing LSEs and the Commission with information on the cost premiums for earlier online dates, which can help the Commission weigh the costs and benefits of further extending OTC unit retirement dates compared to procurement of incremental capacity in those years.

Furthermore, to maximize the chances of bringing as much incremental RA capacity online as possible to meet peak needs in 2021, the Commission should work with LSEs to expedite the procurement and regulatory approval processes. Standard processes and timelines are unlikely to support sufficient incremental system RA capacity coming online by August 1, 2021. The Commission should expedite its decision on the procurement need and authorization as much as possible. The Ruling's proposed schedule has the proposed decision in late Fall 2019 and procurement activities initiated in late 2019 or early 2020.[58] Completing the procurement process and receiving Commission approval of selected projects (in the case of the IOUs) will likely result in less than one year for awarded projects to meet an August 2021 commercial

[58] *See* Ruling at 5.

operation date. Any acceleration of the procurement authorization and approval dates would provide developers more time to bring their projects online and increase the potential number of incremental RA projects available to meet 2021 system RA needs.

The Commission should also issue an Assigned Commissioner's ruling authorizing the IOUs to immediately launch their solicitations to meet their proportional share of 2021, 2022, and 2023 needs, with any procurement from those solicitations contingent on a final Commission decision determining the procurement need and the details of the procurement authorization. To meet the aggressive online date of August 1, 2021, it is critical that the IOUs immediately initiate the solicitation process to procure incremental resources by August 1, 2021, along with resources that could come online in 2022 and 2023. CCAs and ESPs already have the ability to commence their solicitation activity, but IOU procurement activity is sometimes challenged when not previously authorized by the Commission. Table 9 provides an example of different solicitations schedules assuming SCE has approval for an expedited launch before a final Commission decision compared to a solicitation launch after a final Commission decision.

Table 9
Sample Request for Offers ("RFO") Schedules

	RFO Expedited Launch		RFO Launch after Final Decision*	
Event	**Dates**	**Delta (# days)**	**Dates**	**Delta (# days)**
Market Notice of RFO Launch or RFO Launch	8/15/2019	-	1/2/2020	-
Offer Submittal	11/13/2019	90	4/1/2020	90
Contract Execution	1/12/2020	60	5/31/2020	60
Contract Approval Filing	2/11/2020	30	6/30/2020	30
Commission Approval	4/11/2020	60	8/29/2020	60
Online Date	8/1/2021	477	8/1/2021	337

* Final Decision authorizing procurement assumed at the end of 2019.

As shown in Table 9, allowing SCE to launch its solicitation before a final Commission decision on incremental system RA need could give developers 40% more time after Commission approval to achieve an August 1, 2021 online date. This should help to reduce costs to customers and improve project viability by providing developers with more time to complete equipment procurement, permitting, construction, and interconnection. Moreover, there would be no prejudice to customers or other parties by allowing SCE to begin its solicitation process before a final Commission decision because SCE would not execute any contracts before a final decision, and any procurement resulting from the solicitation would be contingent on the Commission's determination of the procurement need and the details of the procurement authorization.

If the Commission issues an Assigned Commissioner's ruling, SCE proposes to immediately launch a solicitation that includes: (1) a fast track for August 1, 2021 online resources, (2) a standard track to include resources that can come online up through August 1, 2023, and (3) consideration for utility-owned storage as discussed in Section b below.

The standard track in the solicitation would allow SCE to consider additional procurement in the event not enough incremental RA capacity can meet the August 1, 2021 online date and/or SCE can more cost-effectively bring resources online in 2022 and 2023 to address system RA needs.

With respect to any contracts signed through the fast track for August 1, 2021 online dates, the Commission should expedite the approval of the contracts through a Tier 3 advice letter process. In the resolution approving SCE's ACES 1 solicitation, the Commission stated that it "intend[ed] to expedite consideration of any contracts resulting from the Aliso Canyon Energy Storage Solicitation,"[59] and the Commission approved the contracts within 30 days of filing.[60] This allowed SCE to bring new energy storage resources online on a very short timeframe to meet a reliability need. The same expedited approval timeline is needed here.

For contracts signed through the standard track, the Commission approval timeline does not need to be as expedited; however, expeditious approval of any contracts is also needed to enhance the changes of resources meeting 2022 and 2023 online dates.

The approval process for potential utility-owned storage is addressed in Section b, and should be authorized in recognition of the significant size of the system RA shortfall, the market power mitigation benefit that results from utilities bidding flexible resources using the Commission's least-cost dispatch requirement, and the need for the IOU to demonstrate the customer benefit of utility-owned energy storage as a condition of Commission approval.

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[59] Resolution E-4791 at 5.

[60] In Resolution E-4804, adopted on September 15, 2016, the Commission approved three RA contracts with new energy storage projects resulting from SCE's ACES 1 solicitation, which were submitted for approval via Tier 3 advice letters on August 15, 2016.

b) The Commission Should Allow Consideration of LSE-Owned Resources to Meet System RA Needs

As discussed in the Ruling and herein, there is likely to be CAISO system RA shortfall as early as 2021, and SCE estimates the need for system RA capacity could be 5,500 MW or more. Given the urgency and significant amount of need, the Commission should authorize consideration of a broad range of options for satisfying the need for incremental system RA capacity. In addition to contracting with third-party-owned resources, LSEs should be permitted to consider LSE-owned resources. CCAs and ESPs have this option without the need for Commission approval, and the Commission should allow the IOUs to consider utility-owned resources as a component of their incremental system RA resource development.

SCE proposes to consider utility-owned storage in comparison to its solicitation(s) for incremental system RA. Utility-owned storage provides unique system and customer benefits, including greater deployment opportunity, increased operations value since utilities operate their resources for the benefit of the electric grid under the Commission's least-cost dispatch standard, and not for a subset of customer or LSE benefit, and enhanced optionality in the use and operation of the facility over time. Additionally, utility land ownership is a key benefit when, as in this situation, a need arises with a short time to deployment. Utility land ownership at or near substations shortens the time needed to deploy resources from the date of need determination because the land is already available. Furthermore, less work may be required to interconnect the resource due its proximity to the substation of interconnection. Utilities also have greater flexibility to relocate, reconfigure, stagger deployment, and/or change technology given a short time to deploy, without having to negotiate costly contract amendments, when energy storage resources are utility-owned.

Utilities are responsible for ensuring a safe, reliable, and affordable electric system, and energy storage is an additional tool to fulfill that mission. Because California utilities have a reliability objective, the operation of utility-owned energy storage resources will prioritize reliability over maximizing market revenues. Indeed, California IOUs do not retain market revenues from the generation resources they own and operate, and instead fully return them to customers through applicable regulatory accounts such as the CAM and the Energy Resource Recovery Account.

Utility ownership also allows the utility to operate and maintain energy storage facilities based on physical limitations, rather than contractual and warranty limitations. For example, in the event of a grid emergency, the utility can prioritize reliability by operating the storage device safely, but beyond its warranted operating parameters, if deemed necessary. In such an event, a third-party should be expected to operate its facilities to maintain the ability to maximize revenues over the life of the facility. Utility bidding of required energy storage systems will also be consistent with least-cost dispatch, which facilitates desired customer outcomes of a cost-efficient energy system, enhanced grid reliability, and improved market function.

When a third-party owns the energy storage facility, that party captures all residual value of the facility past its contracted life, whereas for utility-owned assets, such benefits accrue to customers. Because energy storage is still a relatively nascent technology, the asset life for different technologies and configurations is less certain and therefore difficult to contract around. Additionally, ownership allows the utility to decide what to do with the asset once it determines the end of its asset life is approaching: it can repair the asset, replace it, or decide to retire it. For instance, an energy storage facility may have degraded to such a degree that it is no longer useful as a grid asset for transmission and distribution deferral or congestion relief, but the utility could still use the battery to obtain market revenues through services such as frequency regulation that may not require the battery to be fully charged or discharged, or to repurpose the battery systems for very infrequent uses such as black start capability. If the battery were owned by a third-party, these benefits would be realized by the developer or potentially not captured at all.

In Resolution E-4791 authorizing SCE's ACES 1 solicitation, the Commission found that "it is reasonable to allow utilities to pursue proposals for turnkey project development of 'build and transfer' projects located at the utility's substations or on utility-owned or operated sites" and that this option "would increase the likelihood of resources being timely developed."[61] Similarly, the Commission should authorize the IOUs to pursue utility-owned storage resources as part of their procurement of incremental RA capacity to meet their proportional share of any Commission-identified system RA need. SCE would competitively source the energy storage equipment and installation services for any utility-owned storage and recommends the Commission employ a price competitiveness benchmark similar to that used in SCE's ACES 1 solicitation.[62]

Lastly, as with contracts for third-party-owned resources, the Commission should permit cost recovery for any utility-owned projects developed to meet an IOU's proportional share of the system RA need to be approved by Tier 3 advice letter, as the Commission did in connection with PG&E's recent solicitation to meet local needs.[63]

c) <u>**The Commission Should Clarify Eligibility and Other Requirements for any Incremental RA Procurement**</u>

SCE recommends that the Commission make certain clarifications to the eligibility requirements and other requirements regarding the proposal to require that "each LSE procure, on an all-source basis, its proportional share of a total 2,000 MW new peak capacity statewide, to come online by August 1, 2021" as detailed below.[64]

First, SCE interprets the requirement to procure "new" peak capacity to mean that any resources (new or existing) that are not already considered in the Commission's baseline of resources as shown in the chart, "System RA Supply (Sept. NQC with revised ELCC)" on page 12 of the Ruling, would count towards the requirement. Indeed, the Ruling states that "[a]ny

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[61] Resolution E-4791 at 12, Finding 42.
[62] *See id.* at Finding 51.
[63] *See* Resolution E-4949.
[64] Ruling at 14-15.

procurement by LSEs that is not already reflected in the 2019-2020 IRP baseline assumptions would be counted toward the LSE's proportion of the above requirement."[65] However, the reference to "new" could be interpreted to preclude existing resources and it is not entirely clear which resources were included in the Commission's baseline assumptions.

SCE recommends that the Commission refer to the procurement requirement as a requirement to procure "incremental" (and not strictly new) system RA capacity and that the determination of which resources are incremental be based on whether or not they were in the Commission's baseline assumptions. If a resource was not included in the baseline, it is incremental and thus eligible to count towards an LSE's share of the procurement requirement. If a resource was included in the baseline, it is "non-incremental" or "existing," and would not count towards an LSE's share of the procurement requirement, although it would count towards the Ruling's proposal that SCE procure 500 MW of capacity from existing resources provided other requirements (e.g., being without a contract past 2021) are met. The clarification that any resource not included in the Commission's baseline assumptions is fully eligible to meet an LSE's share of the incremental system RA procurement requirement is appropriate because if a resource was not included in the Commission's baseline assumptions, then its procurement would reduce the expected system RA shortfall determined by the Commission.

Additionally, if an LSE has already executed a contract for system RA capacity for the relevant time period (e.g., 2021 to 2023) from a resource not included in the Commission's baseline, that LSE should be able to count that contract towards its share of the procurement requirement, because the procurement will reduce the estimated system RA shortfall. OTC units should not be considered incremental since any contracting with OTC units should be done through RMR agreements as addressed in response to question 4.

To ensure that all LSEs, market participants, and other parties are clear as to which resources are incremental and which are not, the Commission should publish a list of all

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[65] *Id.* at 15.

resources included in its baseline assumptions that includes the resource name, resource ID, the RA capacity included in the baseline assumptions, and the retirement date, if applicable. This information is integral to the solicitation process and contract selection to ensure incremental resources are procured to address the estimated system RA need and that resources that are already considered in the Commission's baseline are not selected.

Further, which behind-the-meter resources are incremental is not clear cut because behind-the-meter resources are usually made up of aggregations of customer-sited resources that may move in or out of the portfolio. The incrementality issue associated with behind-the-meter resources for meeting a reliability need has and is being considered in a variety of regulatory venues, and most of SCE's recent reliability-related procurement activities of behind-the-meter resources have contained an explanation of SCE's incrementality methodology to be used in that procurement activity. The Commission should ensure that all LSEs are using a consistent incrementality methodology in their procurement to meet the incremental system RA procurement requirement. Otherwise, there may inconsistencies in what is allowed, and the Commission will not have assurance that all LSEs' procurement is adequately addressing the incremental system RA need. SCE suggests this issue be discussed during workshop(s) and clearly delineated in the Commission's final decision ordering resource development by all LSEs.

Second, while the Ruling's focus on system RA needs and reference to "peak capacity" make clear that the procurement requirement's intent is to procure capacity that counts towards system RA requirements, SCE recommends that the Commission explicitly state that each LSE's procurement requirement is measured by NQC MW that count towards system RA requirements and that any procured resources must comply with all RA rules.

Third, the Ruling indicates that the resources eligible to count towards the procurement requirement include "firm imports (with capacity discounted by 1/3 to account for the risk associated with increasing imports)."[66] As explained in SCE's responses to questions 1 and 2, it is not realistic to rely on imports in excess of historical levels to meet future system RA requirements. However, both Commission staff and SCE agree that by 2021, the system may need to rely on all of the MIC just to meet system RA requirements, which is more than double the historical usage of imports for system RA. Given that the system is already over-relying on imports, SCE does not believe that any firm imports (even discounted by 1/3) should count towards LSEs' incremental system RA procurement requirements unless the import is from a new resource that is dynamically scheduled into the CAISO. In that case, the Commission can be sure the capacity is from an incremental resource that is committed to the CAISO. Otherwise, the procurement of additional firm imports will just rely on existing import capability and not incrementally increase the amount of capacity that actually exists to meet California's long-term system RA requirements.

Additionally, the procurement of firm energy deliveries at CAISO interties does not preclude the seller of firm energy from ultimately sourcing the firm energy from within the CAISO markets and delivering to the CAISO interties, thus not actually increasing the amount of system RA capacity committed to meeting California's reliability needs. All of these outcomes dictate against considering firm energy imports as incremental system RA resources, unless they are demonstrated to be sourced and dynamically scheduled from a new resource.

Fourth, while conventional thermal resources that are not included in the Commission's baseline should be considered incremental resources that count towards an LSE's share of the procurement requirement, contracting for thermal resources should be limited to terms less than five years to contain costs and ensure that California remains on track to meet its decarbonization goals.

Finally, although SCE generally supports the Ruling's proposal to allocate the procurement requirement to LSEs on a load share basis based on the IEPR forecasts adopted in

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[66] Ruling at 15.

February 2019,[67] SCE notes that the 2018 IEPR forecast may not fully account for new CCA formation, load growth, and load migration. In the *2018 IEPR Update*, the CEC's recommendations included enhance consideration of CCAs in the demand forecast, stating:

> Energy Commission staff should engage with IOU analysts, CCA analysts, and other stakeholders to vet the reasonableness and accuracy of methods for projecting CCA load growth in the very near term, as well as new CCA formation, load growth, and load migration within existing CCA, and efficiency, self-generation, and rate impacts resulting from CCA programs and tariffs.[68]

While it may not be possible to wait for the 2019 IEPR forecast, the Commission should check the reasonableness of the LSE allocations based on the 2018 IEPR forecast against other sources of load data including LSEs' 2019 IEPR submissions, 2019 IEPR proposed forecasts, and LSEs' Renewables Portfolio Standard Portfolio Plan submissions and make adjustments as necessary.

6. Is the requirement for commercial online date of August 1, 2021 sufficiently clear or are other requirements needed? Explain.

The Commission should clarify that the requirement for a commercial online date of August 1, 2021 means that a project has full deliverability of RA and a must offer obligation by August 1, 2021. This clarification will help to eliminate ambiguity and ensure executed contracts support system reliability needs by August 2021. As addressed in response to question 5, the Commission should also allow commercial online dates in 2022 and 2023 in recognition of the significant incremental system RA needs that exist.

In addition, SCE supports the Ruling's proposal that LSEs report on how they are ensuring delivery of their proportional share of the procurement in the required timeframe and the development status of new resources,[69] but suggests the Commission adopt quarterly

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[67] *See id.*

[68] CEC, *2018 IEPR Update Volume II*, CEC 100-2018-001-V2-CMF, March 21, 2019, at 246, available at: https://efiling.energy.ca.gov/GetDocument.aspx?tn=227391&DocumentContentId=58506.

[69] *See* Ruling at 15.

reporting requirements for all LSEs rather than a one-time inclusion of such information in LSEs' IRP filings. In particular, LSEs should report on their procurement activities and contracted or owned projects' achievement of development milestones leading up to an August 1, 2021 (and 2022 and/or 2023 if adopted by the Commission) online date(s) to ensure that both the LSE's procurement process and the project development is on track to meet the required online date(s). As a reliability-based procurement, it is imperative that resources meet the targeted online date(s) or that sufficient advance notice is provided for contingency purposes if it appears the target online date is at risk. This will allow the Commission to pursue backstop mechanisms if necessary.

SCE's standard for reliability-based contracts requires developers to provide regular development reports that track a set of agreed upon milestones that should be met by certain dates in order to achieve the commercial online date. Missing a milestone could be grounds for contract default, after which SCE could terminate the agreement and seek alternative solutions. Milestones for SCE in-front-of-the-meter projects typically include interconnection status, permitting status, and procurement from downstream suppliers/sub-contractors. Milestones for behind-the-meter projects typically include customer acquisition targets, permitting status, and actual installation of projects at customer sites.

Finally, SCE notes that for in-front-of-the-meter projects, obtaining full capacity deliverability status and an NQC/EFC can be a lengthy process. Although these are required for RA status, it is possible that a resource can be operational and provide reliability benefits without them. In SCE's ACES 1 solicitation, SCE recognized that given the expedited timeframe it may have been impossible for a project to obtain full RA status by the need date. As such, SCE created a contract to allow for reliability benefits to be provided without actually providing RA. In this agreement, for the time period prior to receiving an NQC/EFC, the project is required to submit bids into the CAISO market consistent with RA must offer obligations. Capacity payments are then prorated based on whether or not the facility followed these requirements. In this respect, the obligations are similar to the RA program, in that the facility needs only to make itself available to the market, and specific dispatching was handled by market mechanisms. Although all projects counted towards the procurement requirement should ultimately be required to provide system RA, the Commission should consider allowing this type of approach as an interim mechanism until projects can qualify for RA counting given the aggressiveness of an August 1, 2021 online date.

7. Comment on how demand-side resources included in this new resource procurement should be counted (e.g., as part of a reduction in the system resource adequacy requirement as part of the IEPR, etc.).

In general, demand-side resources should be counted based on current practices to the extent those are applicable. For example, energy efficiency and load-modifying DR should be included in the IEPR load forecast, and supply-side DR can use load impact protocols where historical data is available, or program/contract design parameters for new resources. Behind-the-meter battery-backed DR should be counted on the basis of contracted capacity, as long as the contract provides for effective terms and conditions to incentivize seller's performance. SCE's DR local capacity requirements contracts are examples of such contracts where SCE has the dispatch rights to the DR resources to ensure market participation, and the seller is subject to performance obligations, including payment reductions for under-performance.

Essentially, if SCE procures a contract for battery-backed DR for 1 MW, SCE should be able to count 1 MW towards system RA, and not be subject to load impact protocols or other methods that would potentially yield different results from the assumptions made during the solicitation. Providing for clear direction on how to count and get credit towards system RA requirements for these types of resources is beneficial for stakeholder and market certainty, especially when incremental capacity is being procured and developed close to, and in certain instances, overlapping with, RA compliance deadlines (e.g., year-ahead filing, multi-year forward, year 2, and year 3).

For behind-the-meter solar resources, the Energy Division has been developing an ELCC counting methodology to determine their qualifying capacity to properly measure their RA contribution, similar to utility-scale wind and solar resources. Since the Ruling requires the procured MW to be capable of meeting RA needs, this would require the procured quantities to be denominated in their NQC value. For renewable resources, this will require the use of ELCC to determine the contribution of the resource. However, ELCC values change as the resources employed change in quantity. For example, as more solar resources are deployed, there comes a point where an additional MW of solar does not contribute at all to grid reliability as there are so many solar resources that all grid needs are met by the existing resources during periods when solar irradiance is available. As night falls, the ability of those resources to contribute to reliability is eliminated. ELCC was developed to account for this very phenomenon.[70]

8. <u>Comment on the proposed requirement in Section 2.2 of this ruling that SCE contract for 500 MW of existing resource adequacy capacity from a resource or resources that do not have contracts extending past 2021, for 2-5 years, with cost allocation addressed through a modified CAM mechanism. Parties may also propose an alternative approach.</u>

The Ruling is not clear on the intent of this proposal. It is not clear if the Commission intends SCE to contract with a specific resource or type of resource, or if the proposal is intended as a generic procurement requirement of existing capacity. Unless there is a unique procurement

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[70] The Ruling's use of present ELCC values may inadvertently provide an incentive to build significant amounts of solar generation to address the need. For instance, if all LSEs opted to procure solar resources to meet the 2,000 MW need on a September basis, the current ELCC values would require the procurement of more than 14,000 MW of solar. Such significant quantities of solar would be very likely to push the ELCC values lower and therefore, the procured resources would not actually meet the 2,000 MW need. In multiple proceedings at the Commission, SCE has advocated for utilizing a marginal ELCC methodology where the amount of qualifying capacity a renewable resource receives is determined by the ELCC value in place at the time of its commercial operation. SCE recognizes that it may not be practical to implement a marginal ELCC methodology in time for the immediate procurement requirement, but this effort provides a tangible example of why a marginal ELCC methodology should be undertaken.

need that can only feasibly be undertaken by one LSE, SCE opposes a single central buyer undertaking generic reliability procurement on behalf of all Commission-jurisdictional LSEs. The Legislature and the Commission have already established a CAM process where each IOU conducts reliability procurement on behalf of its service area with the costs recovered on a nonbypassable basis from all customers in that service area through the CAM. That process has worked effectively since its inception and resulted in thousands of MW of reliability procurement. Therefore, unless there is a unique need for one LSE to procure the 500 MW of existing RA capacity here, the Commission should follow the established CAM process and allocate the 500 MW procurement requirement among the IOUs on behalf of their service areas, with costs recovered by each IOU from all customers in their service area through their respective CAM accounts.

If the Commission decides in this instance that there is a unique need that is best met by having one LSE contract for 500 MW, the Commission should clarify the purpose of the procurement and identify why it is unique. SCE does not object to conducting the procurement in such a circumstance, but the responsibility to be the central procurement entity for unique procurements should be rotated among the IOUs if a similar situation occurs in the future.

Moreover, if SCE is ordered to do the procurement, the Commission should direct all three IOUs to collect their customers' share of the costs of the procurement from all customers in their service areas on a nonbypassable basis through their CAM charges, with PG&E and SDG&E billing and collecting such procurement costs as an agent for SCE and being required to transfer the funds so collected to SCE. The Commission should also specify that no agreement among the IOUs is needed to effectuate this cost recovery mechanism, but each IOU should establish the appropriate regulatory accounts to do so. In addition, given the pending PG&E bankruptcy, the Commission should explicitly state that PG&E and SDG&E shall have no dominion or control over the collected funds and that they shall have no discretion to do anything with such funds other than to remit the same to SCE. This cost recovery mechanism is necessary because SCE does not have a mechanism to collect CAM charges from customers outside of its own service area. It would also be infeasible and unduly burdensome for SCE to attempt to collect the costs from approximately 40 LSEs as is currently provided in the Ruling. Collecting the procurement costs through each IOU's CAM charges and requiring each IOU to remit the funds collected therefor to SCE is a reasonable approach, consistent with the intent of the Ruling's proposal.

Finally, some clarification is needed on the specifics of the 500 MW procurement requirement. As discussed in response to question 5, the Commission should clarify that the determination of which resources are "incremental" or "new" and which resources are "existing" should be based on whether the resource was included in the Commission's baseline assumptions. If a resource was included in the baseline, it should count towards the requirement to procure 500 MW of existing RA capacity, provided other requirements are met, including any specific procurement requirements established by the Commission. OTC units should not be included as an existing resource as they should be contracted through RMR agreements as addressed in response to question 4. Additionally, only contracts executed after a final Commission decision through a specific procurement process targeted to meet this procurement need should be eligible to count towards the requirement.

It is also not clear if the 500 MW is a minimum or maximum procurement requirement. Contracting with existing resources that meet all of the eligibility criteria may be lumpy and it may not be feasible to procure exactly 500 MW. As such, SCE suggests that the existing resource procurement requirement of 500 MW be a minimum amount, with a reasonable range above that amount allowed.

Further, SCE supports the Ruling's proposal that LSEs who require Commission approval of their contracts file a Tier 3 advice letter seeking that approval. The IOUs (or SCE) should be permitted to submit any contracts meeting the 500 MW procurement requirement for approval via Tier 3 advice letters.

9. Should any procurement from existing resources be focused on resources that have formally notified the CAISO and the Commission of an intention to retire? Why or why not?

SCE believes this a policy consideration that the Commission can address in any requirement for SCE (or all IOUs) to contract for existing resources. Given the projected deficiency in system RA capacity by summer 2021 and the limited remaining time available to develop new system RA resources, it does make sense to assess the cost required to extend the operation of existing resources that would otherwise retire, if only to provide more time for new, cost competitive clean energy resources to be developed before existing resources retire.

10. If individual LSEs are unable to procure their responsible share of the authorized procurement, should an interim backup mechanism and role be established to ensure the procurement needs are met and that all LSEs pay their fair share? Could this interim backup mechanism be developed and implemented in time to get resources procured and online by August 1, 2021? If yes, describe implementable solutions.

Yes, SCE supports the development of a backstop mechanism and suggests that the development of such a backstop mechanism be discussed during workshop(s). However, if individual LSEs are unable to procure their share of the required procurement, it is unlikely there will be sufficient time for another entity to procure resources that can come online by August 1, 2021. But there may be enough time to conduct backstop procurement to meet a 2022 or 2023 online date, where there is still a need as discussed above. These timing issues should be discussed at the workshop(s).

The outcome of the Ruling's proposed fragmented procurement process would inform how the Commission may consider future procurement, including any backstop procurement. A central procurement entity could be a likely potential solution for backup procurement for resources coming online in 2022 and beyond; however, considerations for whether the need is unique to a certain service area or generic, and who should serve as the central procurement entity, should be further explored in workshop(s). The quarterly progress reports discussed in the response to question 6 could also be part of the backstop mechanism (i.e., provide clear, objective triggers) and provide the Commission with critical information as to when to invoke such a backstop mechanism.

11. If the Commission is unable to develop and implement an interim backup mechanism in time to meet peak system resource adequacy needs in 2021, what type of compliance mechanism will be needed to ensure that LSEs comply with their share of the procurement responsibility? Provide implementable solutions.

Regardless of whether the Commission develops and implements a backstop mechanism in time to meet peak system RA needs in 2021, the Commission should clarify the consequences if an LSE does not satisfy its share of the procurement responsibility. Implementing a penalty mechanism could provide appropriate incentive, but also runs the risk that despite all reasonable efforts, one or more LSE may not be able to meet its requirement for incremental resources to achieve commercial operation by August 1, 2021. How such a penalty mechanism would work and how it would be integrated with the existing RA penalty structure are critical elements in the design of this procurement.

Within the RA proceeding, the Commission has implemented a $6.66/kW-month penalty mechanism for failing to procure sufficient system RA resources.[71] In addition, if the LSE failure resulted in CAISO backstop procurement, the costs of such procurement would be allocated to the deficient LSE. This penalty mechanism ensures that the LSE is responsible for its share of system reliability cost and is incentivized to perform its necessary procurement.

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[71] *See* D.11-06-022 at Ordering Paragraph 5.

SCE believes that the Commission should incorporate its current $6.66/kW-month system RA penalty mechanism for each month of deficiency in meeting an LSE's respective share of the incremental system RA procurement requirement, and then allocate any backstop procurement process costs that are incurred to those LSEs that were deficient.

In order to determine deficiencies, a transparent review and enforcement process would need to be established to clarify the assessment of penalties and the amount, including a process to potentially allow LSEs to transfer some or all of their share of the incremental system RA procurement requirement as a result of load migration. A reporting process including milestones and quarterly reports as discussed in response to question 6 could include how an LSE plans to demonstrate compliance with its share of the incremental system RA procurement requirement. The Commission would then review LSEs' reports and determine if backstop procurement is necessary, and provide a finding of cost responsibility for any such backstop procurement.

Penalties should only be assessed for the period of time in which an LSE is operationally deficient in meeting its incremental system RA procurement requirement. However, the Commission should consider capping the application of penalties to a maximum period (e.g., one to two years), at which time any LSE that is still deficient should be required to shed load to a level that is proportionate to the amount of incremental system RA resources it successfully developed (e.g., an LSE that developed 75% of its required incremental system RA by the conclusion of the penalty period would have to shed 25% of its load). This will prevent chronic non-compliance in the event that an LSE determines the payment of the $6.66/kW-month system RA penalty amount is less costly than developing incremental system RA resources.

12. Is a Tier 3 advice letter the appropriate mechanism to secure Commission approval for contracts associated with the proposals in this ruling, for LSEs who require such approval? Why or why not? Provide an alternative proposal, if desired.

Yes, as explained in response to questions 5 and 8, a Tier 3 advice letter is the appropriate mechanism to secure approval of all contracts and utility investments associated with the proposals in this Ruling, including contracts and utility investments associated with the incremental RA capacity procurement requirement and contracts associated with the 500 MW existing RA capacity requirement. The Commission should expedite the approval of such contracts, particularly for resources coming online by August 1, 2021, as addressed in response to question 5.

13. Provide any other comments you think the Commission would find relevant to its consideration of system resource adequacy issues and potential procurement by 2021.

The Ruling includes a categorization and prioritization of procurement activities potentially necessary in this proceeding by resource category, and a preliminary schedule for the procurement track.[72] For renewables, which are considered medium priority, the potential procurement mechanisms include increased Renewables Portfolio Standard procurement requirements and specified IRP-directed renewables procurement, and the schedule calls for a renewables phase from Winter 2019 to Spring 2020 with a decision in Spring 2020.[73]
While SCE agrees that there is a need to consider procurement of additional renewables to meet

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[72] *See* Ruling at 2-5.
[73] *See id.* at 3-5.

California's decarbonization goals in this proceeding, SCE is concerned about the separation of renewables procurement from the rest of the IRP process.

In particular, the proposed renewables phase of the procurement track would take place and be resolved before LSEs file their next IRPs. It is not clear what assumptions would inform any renewable procurement need that is determined in this phase, which would suggest that it may have to be informed from the last IRP cycle. However, that information will be outdated. The next 2019-2020 IRP cycle will include different assumptions, may include a different GHG target, and LSEs will file different plans. The resulting Reference System Plan and Preferred System Plan may have a very different resource mix than the plans from the last IRP cycle. The Commission should not make significant procurement decisions based on assumptions that are no longer accurate, especially given that the 2019-2020 IRP cycle will be taking place in roughly the same timeframe.

Rather than having a separate renewables phase of the IRP procurement track, SCE recommends that renewable procurement issues be considered as part of the main 2019-2020 IRP cycle in conjunction with consideration of LSEs' IRPs.

III.

CONCLUSION

For all the foregoing reasons, the Commission should adopt SCE's recommendations discussed herein.

Respectfully submitted,

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Appendix A

Natural Gas Plant Retirement and Addition List

Table A-1
Natural Gas Plants Retired Between 2012 and 2019

RESOURCE_ID	GENERATOR NAME	Capacity (MW)	Retirement Date
COCOPP_7_UNIT 6	CONTRA COSTA UNIT 6	337	4/30/2013
COCOPP_7_UNIT 7	CONTRA COSTA UNIT 7	337	4/30/2013
ELSEGN_7_UNIT 3	EL SEGUNDO GEN STA. UNIT 3	335	7/27/2013
MORBAY_7_UNIT 3	MORRO BAY UNIT 3	325	2/5/2014
MORBAY_7_UNIT 4	MORRO BAY UNIT 4	325	2/5/2014
CWATER_7_UNIT 1	COOLWATER GEN STA. UNIT 1	63	1/22/2015
CWATER_7_UNIT 2	COOLWATER GEN STA. UNIT 2	82	1/22/2015
CWATER_7_UNIT 3	COOLWATER STATION 3 AGG.	245	1/22/2015
CWATER_7_UNIT 4	COOLWATER STATION 4 AGG.	246	1/22/2015
ULTOGL_1_POSO	RIO BRAVO POSO	45	7/1/2015
ELSEGN_7_UNIT 4	EL SEGUNDO GEN STA. UNIT 4	335	12/31/2015
COLGA1_6_SHELLW	COALINGA COGENERATION COMPANY	35	12/31/2016
ELCAJN_7_GT1	EL CAJON	16	12/31/2016
MIDSET_1_UNIT 1	MIDSET COGEN. CO.	33	12/31/2016
MOSSLD_7_UNIT 6	MOSS LANDING UNIT 6	754	12/31/2016
MOSSLD_7_UNIT 7	MOSS LANDING UNIT 7	755	12/31/2016
MRGT_7_UNITS	MIRAMAR COMBUSTION TURBINE AGGREGATE	36	12/31/2016
OILDAL_1_UNIT 1	OILDALE ENERGY LLC	40	12/31/2016
PITTSP_7_UNIT 5	PITTSBURG UNIT 5	312	12/31/2016
PITTSP_7_UNIT 6	PITTSBURG UNIT 6	317	12/31/2016
PITTSP_7_UNIT 7	PITTSBURG UNIT 7	530	12/31/2016
SARGNT_2_UNIT	SARGENT CANYON COGEN. COMPANY	32	12/31/2016
ENCINA_7_EA1	ENCINA UNIT 1	106	2/28/2017
INLDEM_5_UNIT 2	Inland Empire Energy Center, Unit 2	366	3/2/2017
BRDWAY_7_UNIT 3	BROADWAY UNIT 3	65	8/3/2017
KEARNY_7_KY3	KEARNY GT3 AGGREGATE	61	1/9/2018
MNDALY_7_UNIT 1	MANDALAY GEN STA. UNIT 1	215	4/28/2018
MNDALY_7_UNIT 2	MANDALAY GEN STA. UNIT 2	215	4/28/2018
MNDALY_7_UNIT 3	MANDALAY GEN STA. UNIT 3	130	4/28/2018
ETIWND_7_UNIT 3	ETIWANDA GEN STA. UNIT 3	320	6/1/2018
ETIWND_7_UNIT 4	ETIWANDA GEN STA. UNIT 4	320	6/1/2018
ENCINA_7_GT1	ENCINA GAS TURBINE UNIT 1	14.5	12/12/2018
ENCINA_7_EA2	ENCINA UNIT 2	103	12/12/2018
ENCINA_7_EA3	ENCINA UNIT 3	109	12/12/2018
ENCINA_7_EA4	ENCINA UNIT 4	299	12/12/2018
ENCINA_7_EA5	ENCINA UNIT 5	329	12/12/2018
OAK C_7_UNIT 1	OAKLAND STATION C GT UNIT 1	55	12/31/2018
OAK C_7_UNIT 2	OAKLAND STATION C GT UNIT 2	55	12/31/2018
OAK C_7_UNIT 3	OAKLAND STATION C GT UNIT 3	55	12/31/2018

RESOURCE_ID	GENERATOR NAME	Capacity (MW)	Retirement Date
DIVSON_6_NSQF	DIVISION NAVAL STATION COGEN	45.48	12/31/2018
NIMTG_6_NIQF	NORTH ISLAND QF	38.62	12/31/2018
PTLOMA_6_NTCQF	NTC/MCRD COGENERATION	20.96	12/31/2018
BASICE_2_UNITS	CALPINE AMERICAN I COGEN.	85.4	5/1/2019
GRNLF1_1_UNITS	Greenleaf 1	49.2	3/11/2019
HNTGBH_7_UNIT 1	HUNTINGTON BEACH GEN STA. UNIT 1	225.75	10/31/2019
REDOND_7_UNIT 7	REDONDO GEN STA. UNIT 7	505.96	10/31/2019
INLDEM_5_UNIT 1	Inland Empire Energy Center, Unit 1	340	not sure
MOSSLD_2_PSP1	MOSS LANDING POWER BLOCK 1	510	not sure
MOSSLD_2_PSP2	MOSS LANDING POWER BLOCK 2	510	not sure
Total		10,684	

Table A-2
Natural Gas Plants Coming Online Between 2012 and 2019

RESOURCE_ID	GENERATOR NAME	Capacity (MW)	Online Date
VESTAL_2_WELLHD	Wellhead Power Delano	49	1/16/2013
WALCRK_2_CTG1	Walnut Creek Energy Park Unit 1	96	3/21/2013
WALCRK_2_CTG2	Walnut Creek Energy Park Unit 2	96	3/21/2013
WALCRK_2_CTG3	Walnut Creek Energy Park Unit 3	96	3/21/2013
WALCRK_2_CTG4	Walnut Creek Energy Park Unit 4	96	3/29/2013
WALCRK_2_CTG5	Walnut Creek Energy Park Unit 5	97	4/30/2013
COCOPP_2_CTG1	Marsh Landing 1	202	5/1/2013
COCOPP_2_CTG2	Marsh Landing 2	201	5/1/2013
COCOPP_2_CTG3	Marsh Landing 3	201	5/1/2013
COCOPP_2_CTG4	Marsh Landing 4	203	5/1/2013
SENTNL_2_CTG1	Sentinel Unit 1	92	5/6/2013
SENTNL_2_CTG2	Sentinel Unit 2	92	5/6/2013
SENTNL_2_CTG3	Sentinel Unit 3	92	5/6/2013
SENTNL_2_CTG4	Sentinel Unit 4	92	5/6/2013
SENTNL_2_CTG5	Sentinel Unit 5	92	5/6/2013
SENTNL_2_CTG6	Sentinel Unit 6	92	5/6/2013
SENTNL_2_CTG7	Sentinel Unit 7	92	5/6/2013
SENTNL_2_CTG8	Sentinel Unit 8	92	5/6/2013
ELSEGN_2_UN2021	El Segundo Energy Center 7/8	264	6/29/2013
ELSEGN_2_UN1011	El Segundo Energy Center 5/6	263	6/29/2013
LECEF_1_UNITS	LOS ESTEROS ENERGY FACILITY AGGREGATE	310	7/31/2013
RUSCTY_2_UNITS	Russell City Energy Center	621	8/8/2013
SEARLS_7_ARGUS	NORTH AMERICAN ARGUS	4	11/15/2013
SEARLS_7_ARGUS	NORTH AMERICAN ARGUS	4	11/15/2013
ESCNDO_6_PL1X2	MMC Escondido Aggregate	49	1/25/2014
SAMPSN_6_KELCO1	KELCO QUALIFYING FACILITY	4	3/5/2014
ETIWND_2_UNIT1	New-Indy Ontario, LLC	16	1/1/2016
SNCLRA_2_UNIT1	New Indy Oxnard	18	4/15/2016
PIOPIC_2_CTG1	Pio Pico Unit 1	106	11/3/2016
PIOPIC_2_CTG2	Pio Pico Unit 2	106	11/3/2016
PIOPIC_2_CTG3	Pio Pico Unit 3	106	11/3/2016
SGREGY_6_SANGER	DYNAMIS COGEN	48	6/1/2017
GRZZLY_1_BERKLY	PE - BERKELEY, INC.	22	2/20/2018
CHINO_6_CIMGEN	O.L.S. ENERGY COMPANY -- CHINO	26	6/27/2018
OTC Carlsbad	Encina Gas Peaker	500	10/1/2018
OTC Stanton Peaker	Stanton Peaker	98	11/1/2019
Total		4,638	